To: E-mail Distribution list for PSB Docket No. 7523

From: Public Service Board Staff

Date: June 26, 2009

Re: Revised issues list

Attached is the revised issues list that was discussed in the Clerk of the Board's June 22, 2009, memorandum, and at the June 19, 2009, workshop. The June 22 memorandum established a deadline of July 2, 2009, for substantive comments on the list of issues, with reply comments due July 9, 2009.

The July 2 comments may address any of the issues listed; however, given the significant number of issues, Board staff recommend that participants focus their July 2 comments on issues that must be addressed to meet the September 15, 2009, statutory deadline. These include: (1) development of standard offer contract terms; (2) review of the default prices established by Act 45[1]; (3) establishing a queuing process; and (4) determining eligibility of projects.

Any comments filed in PDF format must be submitted in a form that permits the Board and other participants to search the document and extract text.

The following list of issues is not meant to be the definitive list of all issues that must be addressed in this proceeding. Board staff anticipate that there will be other issues that will arise in comments and workshops and this list is not meant to curtail such issues. Instead, the purpose of the list is to focus the process on the issues that must be addressed by the Board to meet the deadlines contained in Act 45.

An all-day workshop will be held in this docket on Thursday, July 16, 2009, starting at 9:30 A.M. Notice of the location of the workshop will be provided to you next week.

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[1] The full text of Act 45 can be found at http://www.leg.state.vt.us/docs/2010/Acts/ACT045.pdf

Docket 7523 - Issues List

Renewable Cost Issues

1. Gathering data on costs of different renewable sources
   a. Is there publicly available information that the Board can rely upon? If so, how can we access and apply the information?
   b. Do earlier Board dockets provide useful cost data on renewable energy projects? If so, which ones and what data?
   c. If not, should we require information from all developers/vendors?
   d. Confidentiality - should some data be protected? If so, how do other parties evaluate?
   e. Will electric utilities be required to disclose their cost of renewable energy projects that they construct?
2. Evaluation of data
   a. The Board is considering hiring a contractor to assist with data development and analysis. Are there any issues with this approach?
   b. What process should the Board employ to obtain input from developers/vendors and other stake holders?
   c. What is the standard of review that the Board should employ when looking at cost data? Should the Board only alter the statutory prices if it finds a major difference?
   d. How will the Board determine whether new deployment or the pace of new deployment of renewable projects is occurring as a direct result of the Standard Offer?
3. What level of granularity should prices have? One for each type of resource, or different prices based upon certain characteristics?
   a. If we aim for granularity, is there enough data to support each set of prices?
   b. What costs, and thus prices, of different capacity sized plans of the different renewable resources should be addressed?
   c. What is the appropriate capacity differentiation?
   d. How will the Board determine the price for each type of technology?
4. How do we value the tax credits and other support, such as grant programs?
   a. What credits and grants are available?
   b. Should standard offers differentiate between plants that can and cannot take advantage of tax credit(s) available?
5. How should the Board value the cost of any system impact or facilities or stability studies required in order to interconnect? In particular, does this create a barrier for smaller projects?
   a. What share of the interconnection costs should be borne by the project developer?
6. How should the Board determine the return on equity for purposes of setting a standard rate?
   a. What proportion of the cost should be assumed to be equity?

7. How should the Board calculate the adjustment factor so that prices are high enough, but not excessive?
    a. Should this adjustment factor incorporate an incentive associated with production at the most valuable times (i.e., peak) or associated with the geographic location of the generation unit (i.e., constrained areas)?
8. How should the Board incorporate wheeling charges for power purchased pursuant to a standard offer contract?
    a. Can these charges be minimized or avoided and still be consistent with FERC requirements?
    b. If strategies can be developed to minimize or avoid wheeling charges, will they be precedential and what are the long-term policy implications?
    c. Should system avoided losses be incorporates as well?
    d. Do FERC requirements apply in the case of distribution connected generation?

<u>Implementation Issues</u>

9. Under the statute, the utilities receive RECs associated with SPEED projects.
    a. Should the owner be required to apply for RECs and, if so, for resale into what markets?
    b. Should the producers have affirmative obligations to work with the utilities to assist in the sale and retirement of RECs and other attributes associated with power purchased under a standard offer contract?
    c. Should the attribute be tracked in the NEPOOL GIS?
    d. Should the Board create a mechanism to ensure that REC's are not claimed by more than one party?
    e. How will we ensure that those developing projects are given adequate notice that participation in the standard offer program limits their ability to make claims regarding on-site renewable energy use?
10. Similarly, for capacity, ancillary services and other products including emerging products, are there any steps that need to be taken to assure that utilities receive any associated payments or credits?
    a. Should the asset be administered in the ISO system or remain outside the ISO system and be treated as a load reducer?
11. Project Eligibility Issues
    a. What steps must a developer take to qualify for the rates in effect at a particular point in time? Contract? Construction? CPG? Letter of intent? Who will manage the queue?
    b. What process should the Board put in place to allow developers who want to put projects into service if the interim rates are set in September? Should the Board develop a separate project queue for such projects? Would this be consistent with the statute?
    c. How long can a developer hold a rate, or their spot in the queue?
    d. Should there be two queue's, one for rate, and one for interconnection?

e. Should there be formal eligibility requirements for contract award or participation in the program? If so, what should these eligibility requirements be? Should they vary by technology?
f. Given the limits on the program size is there need to prevent strategic behavior (e.g., hoarding of contracts or project queue positions)? If so, how can this be done without creating excessive barriers to entry? Should some form of security be required or the proponent be required to demonstrate that they have advanced the development of the project?
g. How should the Board address the fact that the standard offer must be in place until 50 MW have been commissioned (not approved)? Does the standard offer need to contain provisions so that only the first 50 MW qualify for the rates?
h. Should the Board reserve a portion of the 50 MW for smaller projects or projects from particular types of resources? What shares should be so reserved?
i. How should the Board factor in utility projects (that may reduce the 50 MW maximum)?
    i. Should the entire project count towards the owning utility's cap, or should only their load share (percentage) count toward the cap?
j. Can existing facilities, such as net metering projects, qualify for the new SPEED rates? Should refurbished projects or the output from expanded projects be able to participate?
k. On a going-forward basis, what is the interrelationship between the Standard Offer Contract and the SPEED and net-metering programs?
l. Should the Board set a minimum kW size to qualify?
    i. Should the Board set qualifications criteria that are inclusive of residential scale systems?

12. How should future renewable energy technology be considered or addressed?
13. Interconnection. Is it necessary or appropriate to revise the Board's interconnection rule for smaller (150 kw or less) renewable projects?
    a. Should the Board reconsider its net-metering interconnection standards under Rule 5.100 and the terms and conditions of the interconnection Rule 5.500 to create a unified interconnection standard for all interconnected electric generation?
    b. Should interconnection of projects with a capacity of 250 kW and less follow the net metering rule?
    c. Should there be a different interconnection rule for different technologies?
14. What, if any, standard should the Board adopt for metering and reporting of SPEED projects eligible for the cost-based pricing under a Standard Offer Contract?
    a. Who will be responsible for metering and reporting in connection with standard offer power allocated by the SPEED Facilitator to utilities?
15. The statute specifies that the term of the contract varies from 10 to 25 years. Who should decide on the duration?
16. Do all projects have to apply under Title 30, Section 248 (or 248(j))?

a. Do all projects apply under Board Rule 5.500?
b. Is the Board prepared to handle a large quantity of Section 248 or 248(j) dockets, and is there potential to delay other Utility 248 requests for infrastructure upgrades?
c. Is the applicant subject to the standard rate at the time of application or approval in the event of an unusual delay in granting a Section 248 permit?

17. Should this proceeding address the development of a Section 248 permitting process for standard offer plants that is similar to what is done for net metered systems? If so, what is the appropriate avenue for developing such a review process?
18. If farm methane projects are allowed to retain ownership of the RECs:
    a. Will this require a separate standard contract for farm methane projects?
    b. Should the value of the RECs be included in determining an appropriate rate for methane projects?
19. The eligibility date for standard offer contracts for non-utility-owned plants is not clearly listed in the statute, thus the PSB may need to make a determination on the eligibility date for non-utility plants as soon as possible.
    a. What date should be selected?
    b. What criteria should the Board employ in determining an eligibility date?
    c. How should this Board establish, as quickly as possible, parameters that will enable project development to continue without a construction season hiatus while we work out the standard offer program process?
20. The law establishes a 2.2 MW size limit on projects.
    a. Does this prohibit expanding a project if it is eligible for feed-in rates?
    b. Could a developer, at a later date, add additional solar panels or wind turbines to an existing SPEED project?
21. What process should the Board use, and what standards should the Board rely on, to determine where "equity requires" that a retail electricity provider be relieved, in whole or in part from standard offer purchases, if it makes a showing that it receives at least 25% of its energy from qualifying SPEED resources?
22. Would an auction mechanism be a useful means for determining the rates necessary to meet the statutory directive that requires a price "sufficient . . . for the rapid development and commissioning of plans and does not exceed the amount needed to provide such an incentive"?

<u>SPEED Contract/Facilitator Issues</u>

23. SPEED Facilitator. Board rules limit the SPEED Facilitator's ability to enter into contracts. Do these need to be amended? Or has the statute obviated the need to change the rule? Can the matter be resolved through an order issued in this investigation?
24. SPEED Facilitator standard contract. What should a standard contract contain?
    a. Can we use the VEPPI contracts as a model?
    b. What reporting requirements should be included?

25. How should the costs of the SPEED Facilitator be apportioned between developers and utilities?
    a. Should the allocation be 50/50 as in the small power arrangements?
    b. How would this allocation occur for small projects?
26. What skills/expertise should the SPEED facilitator have? For example, should the SPEED facilitator have deep knowledge of the NEPOOL GIS system for tracking attributes of a project?
27. Will all Standard Offer generation projects be treated the same way as far as paying costs for metering, transformers, losses, data collection, etc. or will ther be different rules for smaller generators, and if so where will the cutoff be?
28. What contract provisions are needed to protect ratepayers? What contract provisions should be avoided to limit undue barriers to these projects?

<u>Utility Settlement and Billing</u>

29. How will extremely small SPEED projects be allocated to utilities? (This is especially important in the context of small resources – i.e., 10kW – where a pro rata allocation could result in some utilities being allocated less than 1 kW on an hourly basis.)
30. Are there any barriers to implementation inherent in the ISO New England settlement process used by utilities to settle generation contracts and, if so, how can they be overcome?
31. How will the utility allocations be treated in the context of settlement with ISO New England?
32. How will REC's be allocated, especially in the context of utility allocations of less than 1 kW?
33. Will a minimum generator size be required to facilitate utility settlement?
34. How will the utility generator provisions of the legislation be implemented?
    a. If CVPS and GMP build large numbers of utility owned generators, standard offer charges could be shifted to the remaining municipal and cooperative customers, skewing overall rate impacts. Should there be limits on utility offsets?
    b. Credits received for projects developed by retail electricity providers appear to allow for a proportional reduction in obligations to receive power under the feed-in tariff program. In addition to reviewing the effects of development by retail providers on the 50 MW ceiling, how will the Board implement the adjustment for the retail electricity providers?

<u>Other Cost and Pricing Issues</u>

35. How should factors like outage rates, availability, capacity factor, and generic performance criteria be used in developing the appropriate rate?
36. How should the end of life value be considered in the cost calculation for the various technologies?
    a. Should the projects become the property of the ratepayers upon the expiration

of the contract?

37. Should the rate structures differentiate components of each project, such as energy, capacity, and RECs.?
38. Should rates be designed to include peak and off peak components as well as incentives to produce at the most useful times?
39. Should rates include a geographic component to promote generation in constrained areas?
40. Should property tax implications for the installation of renewable systems and income tax implications from the sale of output from the facilities be addressed in developing costs?
41. Should the rate reflect any needed system improvements resulting from the installation of a renewable system on the grid?
42. How should the contract price reflect: (1) the fact that a portion of project costs will escalate over time? (2) there may be economies of scale related to larger capacity projects?
43. Should the Board establish a Vermont-manufactured multiplier to promote the installation and use of technology manufactured in the state? If so, what level of support would be appropriate?
44. How should the Board address public (non-taxable) entities versus private (taxable) entities in determining generic costs?
45. Wind energy has different generic costs at different mean average wind speeds; how should the Board decide the appropriate state mean wind speed used to determine costs?
46. How should issues related to capital structure and financing be addressed in developing pricing information?